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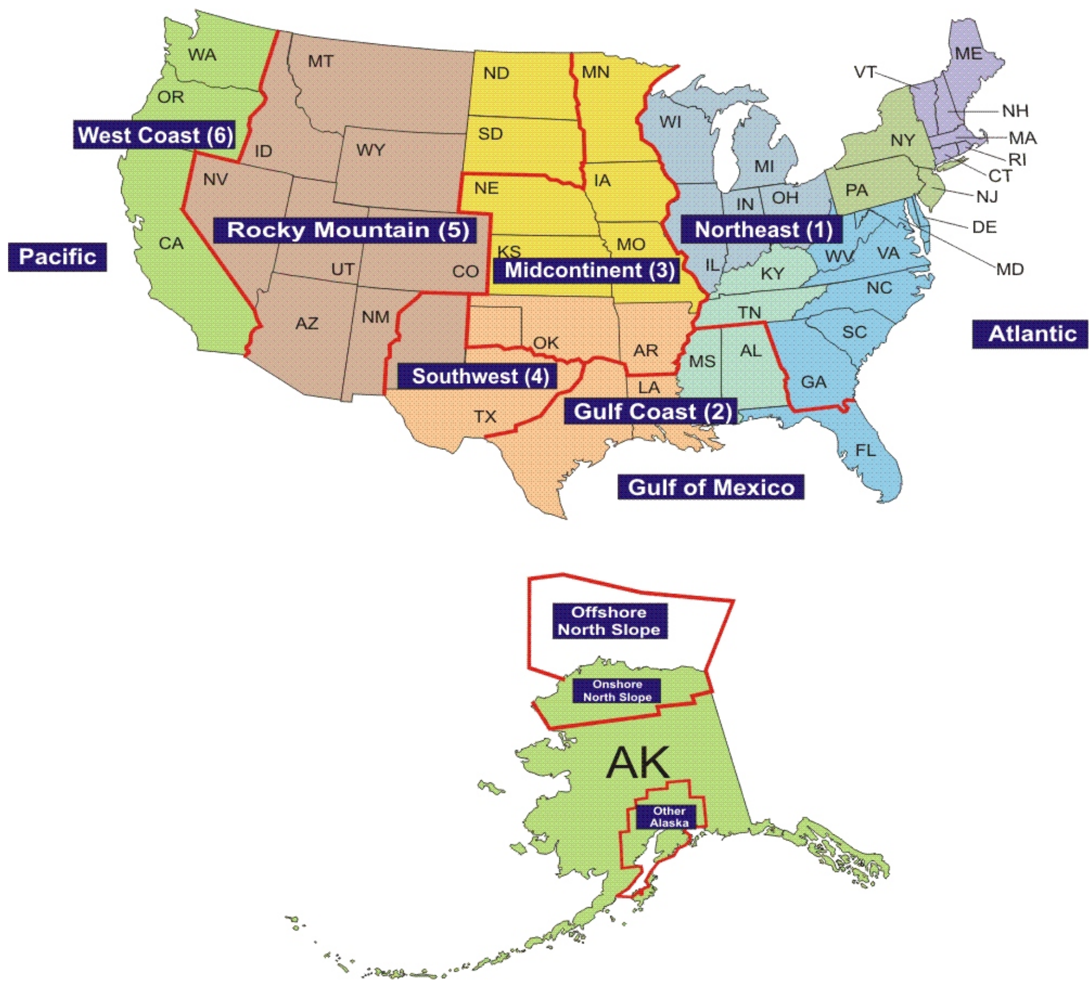
# Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas natural gas exploration and development on a regional basis (Figure 7). The OGSM is organized into 4 submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply Submodule, Oil Shale Supply submodule, and Alaska Oil and Gas Supply Submodule. A detailed description of the OGSM is provided in the EIA publication, *Model Documentation Report: The Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(2010), (Washington, DC, 2010). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States.

**Figure 7. Oil and Gas Supply Model Regions**




Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Conventional oil recovery includes improved oil recovery processes such as water flooding, infill drilling, and horizontal continuity, as well as enhanced oil recovery processes such as $CO_2$ flooding, steam flooding, and polymer flooding. Conventional natural gas supply includes resources from low permeability tight sandstone formations. Nonconventional recovery includes unconventional oil recovery from highly fractured, continuous zones (e.g. Austin chalk and Bakken shale formations) and unconventional gas recovery from low permeability shale formations and coalbeds.

# Key Assumptions

## *Domestic Oil and Natural Gas Technically Recoverable Resources*

Domestic oil and natural gas technically recoverable resources [1] consist of proved reserves, [2] inferred reserves, [3] and undiscovered technically recoverable resources. [4] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior. [5] Supplemental adjustments to the USGS nonconventional natural gas resources are made to add some frontier plays that were not quantitatively assessed by the USGS. Similarly, 28.7 billion barrels are added to U.S. inferred reserves to reflect a revised assessment of the potential of enhanced oil recovery to increase the recoverability of remaining in-place resources. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a field-by-field basis from a variety of sources including trade press. Published estimates in Tables 9.1 and 9.2 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2008.

**Table 9.1. Technically Recoverable U.S. Crude Oil Resources as of January 1, 2008**

(billion barrels)

| | Proved Reserves | Inferred Reserves | Undiscovered Technically Recoverale Resources | Total Technically Recoverable Resources |
|---|---|---|---|---|
| Lower 48 Onshore | 14.2 | 48.3 | 25.3 | 87.8 |
| Northeast | 0.3 | 0.2 | 0.7 | 1.3 |
| Gulf Coast | 1.7 | 2.8 | 8.6 | 13.2 |
| Midcontinent | 1.1 | 7.1 | 1.0 | 9.1 |
| Southwest | 5.4 | 22.7 | 2.6 | 30.6 |
| Rocky Mountain | 2.7 | 8.2 | 10.1 | 20.9 |
| West Coast | 3.1 | 7.3 | 2.3 | 12.7 |
| Lower 48 Offshore | 4.4 | 10.3 | 47.2 | 61.9 |
| Gulf (currently available) | 3.8 | 9.4 | 30.3 | 43.5 |
| Easter/Central Gulf (unavailable until 2022) | 0.0 | 0.0 | 3.7 | 3.7 |
| Pacific | 0.7 | 0.9 | 10.5 | 12.0 |
| Atlantic | 0.0 | 0.0 | 2.7 | 2.7 |
| Alaska (Onshore and Offshore) | 4.2 | 2.1 | 42.0 | 48.3 |
| Total U.S. | 22.8 | 60.7 | 114.5 | 198.0 |

Note:Resources in areas where drilling is officially prohibited are not included in this table. Estimates of the resources within a 50-mile buffer off the Atlantic coast are also excluded from the technically recoverable volumes.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2008.

**Table 9.2. Technically Recoverable U.S. Natural Gas Resources as of January 1, 2008**

(trillion cubic feet)

| | Proved Reserves | Inferred Reserves | Undiscovered Technically Recoverale Resources | Total Technically Recoverable Resources |
|---|---|---|---|---|
| **Lower 48 Onshore Non Associated** | 192.7 | 980.9 | 208.3 | 1382.0 |
| **Conventional** | 149.0 | 595.9 | 144.1 | 889.0 |
| Northeast | 10.0 | 55.5 | 8.9 | 74.4 |
| Gulf Coast | 45.2 | 154.3 | 75.2 | 274.6 |
| Midcontinent | 28.8 | 41.8 | 16.6 | 87.2 |
| Southwest | 12.4 | 51.9 | 14.6 | 78.9 |
| Rocky Mountain | 52.0 | 271.1 | 21.9 | 345.0 |
| West Coast | 0.7 | 21.2 | 7.0 | 28.9 |
| **Shale Gas** | 21.8 | 295.6 | 50.9 | 368.4 |
| Northeast | 6.0 | 73.2 | 0.0 | 79.2 |
| Gulf Coast | 6.6 | 90.3 | 0.0 | 96.9 |
| Midcontinent | 1.5 | 51.0 | 0.0 | 52.5 |
| Southwest | 7.5 | 59.5 | 0.0 | 67.0 |
| Rocky Mountain | 0.2 | 21.6 | 0.0 | 21.9 |
| West Coast | 0.0 | 0.0 | 50.9 | 50.9 |
| **Coalbed Methane** | 21.9 | 89.4 | 13.3 | 124.6 |
| Northeast | 1.8 | 4.6 | 0.0 | 6.4 |
| Gulf Coast | 1.8 | 5.1 | 0.0 | 6.8 |
| Midcontinent | 0.9 | 4.6 | 8.0 | 13.5 |
| Southwest | 0.0 | 0.0 | 0.0 | 0.0 |
| Rocky Mountain | 17.4 | 75.1 | 1.8 | 94.3 |
| West Coast | 0.0 | 0.0 | 3.6 | 3.6 |
| **Lower 48 Offshore Non Associated** | 12.4 | 50.7 | 233.0 | 296.0 |
| Gulf (currently available) | 12.4 | 50.4 | 167.6 | 230.4 |
| Eastern/Central Gulf (unavailable until 2022) | 0.0 | 0.0 | 21.5 | 21.5 |
| Pacific | 0.1 | 0.3 | 18.4 | 18.7 |
| Atlantic | 0.0 | 0.0 | 25.5 | 25.5 |
| **Associated-Dissolved Gas** | 20.7 | -- | 117.2 | 137.9 |
| **Alaska** | 11.9 | 24.8 | 266.1 | 302.0 |
| **Total U.S.** | 237.7 | 1056.3 | 824.6 | .2118.7 |

Note: Resources in areas where drilling is officially prohibited are not included in this table. Estimates of the resources within a 50-mile buffer off the Atlantic coast are also excluded from the technically recoverable volumes. The Alaska value does not include stranded Arctic gas. The 117.2 Tcf of undiscovered Associated-Dissolved natural gas includes inferred reserves.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International; Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves -- EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2008.

## *Lower 48 Offshore*

The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) is a play-level model used to analyze crude oil and natural gas supply from onshore lower 48 sources. The methodology includes a comprehensive assessment method for determining the relative economics of various prospects based on financial considerations, the nature of the resource, and the available technologies. The general methodology relies on a detailed economic analysis of potential projects in known fields, enhanced oil recovery projects, and undiscovered resources. The projects which are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. For crude oil projects, advanced secondary or improved oil recovery techniques (e.g. infill drilling and horizontal continuity) and enhanced oil recovery (e.g. $CO_2$ flooding, steam flooding, and polymer flooding) processes are explicitly represented. For natural gas projects, the OLOGSS represents both conventional (includes tight gas) and unconventional (shale gas and coalbed methane) natural gas supply.

The OLOGSS evaluates the economics of future crude oil and natural gas exploration and development from the perspective of an operator making an investment decision. An important aspect of the economic calculation concerns the tax treatment. Tax provisions vary with the type of producer (major, large independent, or small independent). For the AEO2010, the economics of potential projects reflect the tax treatment provided by current laws for large independent producers. Relevant tax provisions are assumed unchanged over the life of the investment. Costs are assumed constant over the investment life but vary across region, fuel, and process type. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

## *Technology*

Technology advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curves which represent the adoption of the technology: convex, concave, sigmoid/logistic or linear. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The specific technology levers and assumptions are shown in Table 9.3.

**Table 9.3. Onshore Lower 48 Technology Assumptions**

| | Ultimate Market Penetration | Market Penetration Curve | Probability of Successful R&D | Probability of Implementation | Drilling Success Rate | Exploration Sucess Rate | Injection Rate | Estimated Ultimate Recovery |
|---|---|---|---|---|---|---|---|---|
| Conventional Oil | | | | | | | | |
| Infill Drilling | 59% | linear | 50% | 44% | 3% | 3% | -- | 1% |
| Horizonal Continuity | 60% | linear | 51% | 44% | 3% | 3% | 25% | 2.3% |
| Horizonal Profile | 61% | concave | 49% | 45% | 3% | 3% | 2% | 1% |
| CO2 Flooding | 61% | linear | 51% | 43% | 3% | 3% | 38% | 4.2% |
| Steam Flooding | 60% | logistic | 49% | 44% | 3% | 3% | 1% | 9% |
| Polymer Flooding | 61% | concave | 50% | 44% | 3% | 3% | 12.3% | 6% |
| Profile Modification | 59% | concave | 51% | 42% | 3% | 3% | -- | 6% |
| Undiscovered | 60% | concave | 48% | 44% | 3% | 3% | -- | 8% |
| Unconventiona Oil | 60% | concave | 48% | 44% | 3% | 3% | -- | 8% |
| | | | | | | | | |
| Conventional Gas | | | | | | | | |
| Developing | 61% | linear | 48% | 46% | 3% | 3% | -- | 4% |
| Undiscovered | 61% | linear | 49% | 45% | 3% | 3% | -- | 7% |
| Shale Gas | | | | | | | | |
| Developing | 61% | linear | 48% | 45% | 3% | 3% | -- | 8% |
| Undiscovered | 61% | linear | 48% | 45% | 3% | 3% | -- | 7% |
| Coalbed Methane | | | | | | | | |
| Developing | 60% | linear | 50% | 44% | 3% | 3% | -- | 5% |
| Undiscovered | 60% | linear | 49% | 43% | 3% | 3% | -- | 5% |

Source: Office of Integrated Analysis and Forecasting.

### *$CO_2$ Enhanced Oil Recovery*

For $CO_2$ miscible flooding, the OLOGSS incorporates both industrial and natural sources of $CO_2$. The industrial sources of $CO_2$ are:

- Hydrogen plants
- Ammonia plants
- Ethanol plants
- Cement plants
- Refineries
- Fossil fuel power plants

Technology and market constraints prevent the total volumes of $CO_2$ (Table 9.4) from becoming immediately available. The development of the $CO_2$ market is divided into 3 periods: 1) technology R&D, 2) infrastructure construction, and 3) market acceptance. The capture technology is under development during the R&D phase, and no $CO_2$ is available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no $CO_2$ is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of $CO_2$ first become available. The number of years in each development period is shown in Table 9.5.

**Table 9.4. Maximum Volume of $CO_2$ Available**
(billion cubic feet)

| OGSM Region | Natural Source of $CO_2$ | Industrial Sources of $CO_2$: Hydrogen | Ammonia | Ethanol | Cement | Refineries | Fossil Fuel |
|---|---|---|---|---|---|---|---|
| Northeast | -- | 12 | -- | 31 | 272 | 444 | 12980 |
| Costs | 80 | 146 | 118 | -- | 131 | 1152 | 3930 |
| Midcontinent | 13 | 8 | 8 | 77 | -- | 103 | 752 |
| Southwest | 742 | -- | -- | -- | -- | 292 | -- |
| Rocky Mountains | 114 | 14 | -- | -- | -- | 91 | 4041 |
| West Coast | -- | 163 | -- | -- | -- | -- | 60 |
| Total | 949 | 343 | 126 | 108 | 403 | 2082 | 21763 |

Source: Office of Integrated Analysis and Forecasting.

**Table 9.5. $CO_2$ Availability Assumptions**

| Source Type | R&D Phase (years) | Infrastructure Development (years) | Market Acceptance (years) | Ultimate Market Acceptance |
|---|---|---|---|---|
| Natural | 0 | 1 | 3 | 100% |
| Hydrogen Plants | 5 | 4 | 7 | 100% |
| Ammonia Plants | 5 | 4 | 7 | 100% |
| Ethanol Plants | 5 | 4 | 7 | 100% |
| Cement Plants | 8 | 5 | 7 | 100% |
| Refineries | 8 | 8 | 7 | 100% |
| Fossil Fuel Plants | 8 | 8 | 7 | 100% |

Source: Office of Integrated Analysis and Forecasting.

The cost of $CO_2$ from natural sources is a function of the oil price. For industrial sources of $CO_2$, the cost to the producer includes the cost to capture, compress to pipeline pressure, and transport to the project site via pipeline within the region (Table 9.6). Inter-regional pipelines are not built.

**Table 9.6. Industrial $CO_2$ Capture & Transportation Costs by Region and Source**
($/mcf)

| OGSM Region | Industrial Sources of $CO_2$: Hydrogen | Ammonia | Ethanol | Cement | Refineries | Fossil Fuel |
|---|---|---|---|---|---|---|
| Northeast | $0.92 | $0.92 | $0.99 | $2.93 | $2.94 | $3.22 |
| Costs | $9.92 | $0.93 | $1.01 | $2.92 | $2.93 | $3.22 |
| Midcontinent | $0.92 | $0.90 | $1.02 | $2.91 | $2.94 | $3.22 |
| Southwest | $0.92 | $0.92 | $1.01 | $2.92 | $2.94 | $3.22 |
| Rocky Mountains | $0.92 | $0.92 | $1.01 | $2.92 | $2.94 | $3.22 |
| West Coast | $0.92 | $0.92 | $1.01 | $2.92 | $2.94 | $3.22 |

Source: Office of Integrated Analysis and Forecasting.

## *Lower 48 Offshore*

Most of the Lower 48 offshore oil and gas production comes from the deepwater of the Gulf of Mexico (GOM). Production from current producing fields and industry announced discoveries largely determine the short-term oil and natural gas production projection.

For currently producing fields, a 20-percent exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses a 30-percent exponential decline. Fields that began production after 2008 are assumed to remain at their peak production level for 2 years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2007 are shown in Table 9.7. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Production is assumed to

- ramp up to a peak level in 2 to 4 years depending on the size of the field,

**Table 9.6. Assumed Rates of Technological Progress for Unconventional Gas Recovery**

| Field/Project Name | Block | Water Depth (feet) | Year of Discovery | Field Size Class | Field Size (MMBoe) | Start Year of Production |
|---|---|---|---|---|---|---|
| Great White | AC857 | 8717 | 2002 | 14 | 372 | 2010 |
| Telemark | AT063 | 4457 | 2000 | 12 | 89 | 2010 |
| Droshky | GC244 | 2900 | 2007 | 12 | 89 | 2010 |
| Hornet | GC379 | 3878 | 2001 | 13 | 182 | 2010 |
| GC488 | GC449 | 3266 | 2008 | 12 | 89 | 2010 |
| MC503 | MC503 | 3099 | 2008 | 14 | 372 | 2010 |
| Cascade | WR206 | 8143 | 2002 | 14 | 372 | 2010 |
| Chinook | WR469 | 8831 | 2003 | 14 | 372 | 2010 |
| Trident | AC903 | 9743 | 2001 | 13 | 182 | 2011 |
| Ozona | GB515 | 3000 | 2008 | 12 | 89 | 2011 |
| Knotty Head | GC512 | 3557 | 2005 | 15 | 691 | 2011 |
| West Tonga | GC726 | 4674 | 2007 | 12 | 89 | 2011 |
| Ringo | MC546 | 2460 | 2006 | 14 | 372 | 2011 |
| Tubular Bells | MC725 | 4334 | 2003 | 12 | 89 | 2011 |
| Pony | GC468 | 3497 | 2006 | 13 | 182 | 2012 |
| Norman | GB434 | 5000 | 2006 | 15 | 691 | 2013 |
| Puma | GC823 | 4129 | 2003 | 14 | 372 | 2013 |
| Kaskida | KC292 | 5860 | 2006 | 15 | 691 | 2013 |
| Big Foot | WR029 | 5235 | 2005 | 12 | 89 | 2013 |
| St. Malo | WR678 | 7036 | 2003 | 14 | 372 | 2013 |
| Jack | WR759 | 6963 | 2004 | 14 | 372 | 2013 |
| Grand Cayman | GB517 | 5000 | 2006 | 13 | 182 | 2014 |
| Kodiak | MC771 | 4986 | 2008 | 15 | 691 | 2015 |
| Stones | WR508 | 9556 | 2005 | 12 | 89 | 2015 |
| Entrada | GB782 | 4690 | 2000 | 14 | 372 | 2016 |
| Freedom | MC948 | 6095 | 2008 | 15 | 691 | 2017 |
| Julia | WR627 | 7087 | 2007 | 12 | 89 | 2017 |
| Hal | WR848 | 7657 | 2008 | 12 | 89 | 2018 |
| Tiber | KC102 | 4132 | 2009 | 16 | 1419 | 2019 |

Source: Office of Integrated Analysis and Forecasting.

- remain at the peak level until the ratio of cumulative production to initial resource reaches 20 percent for oil and 30 percent for natural gas,
- and then decline at an exponential rate of 20-30 percent.

The discovery of new fields (based on MMS's field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described in the previous paragraph).

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The specific technology levers and values for the offshore are presented in Table 9-8.

**Table 9.8. Offshore Exploration and Production Technology Levels**

| Technology Level | Total Improvement (percent) | Number of Years |
|---|---|---|
| Exploration success rates | 30 | 30 |
| Delay to commence first exploration and between | 15 | 30 |
| Exploration & development drilling costs | 30 | 30 |
| Operating cost | 30 | 30 |
| Time to construct production facility | 15 | 30 |
| Production facility construction costs | 30 | 30 |
| Initial constant production rate | 15 | 30 |
| Decline rate | 0 | 30 |

Source: Office of Integrated Analysis and Forecasting.

## *Oil Shale Liquids Production*

Projections for oil shale liquids production are based on underground mining and surface retorting technology and costs. The facility parameter values and cost estimates assumed in the projection are based on information reported for the Paraho Oil Shale Project, with the costs converted into 2004 dollars.[6] Oil shale rock mining costs, however, are based on current Rocky Mountain underground coal mining costs, which are representative oil shale rock mining costs. Oil shale facility investment and operating costs are assumed to decline by 1 percent per year. The construction of commercial oil shale production facilities is not permitted prior to 2017, based on the current status of petroleum company research, development and demonstration (RD&D) programs.

Although the petroleum company oil shale RD&D programs are focused on the in-situ production of oil shale liquids, the underground mining and surface retorting process shares many similarities with the in-situ process. Moreover, because the in-situ process is still at the experimental stage, there are no publicly available estimates as to the in-situ process capital and operating costs required to produce a barrel of oil shale liquids at a commercial scale. Consequently, the underground mining and surface retorting costs, in conjunction with the 1 percent per year cost decline, are intended to be a surrogate for the in-situ process costs.

Oil shale production facilities are assumed to be built when the net present value of the discounted cash flow exceeds zero. The discounted cash flow calculation uses a calculated discount rate that takes into consideration the financial risk associated with building oil shale facilities. Oil shale facilities take 5 years to construct, with an additional 5 years required to bring an in-situ facility into full production. An assumed technology penetration rate specifies that 5 years must pass from the time the first facility begins construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility begins construction. Oil shale liquids production is not resource constrained, because approximately 400 billion barrels of petroleum liquids exist in oil shale rock with at least 30 gallons per ton of rock.

Because the in-situ process is still at the experimental stage, and because the underground mining and surface retorting process is unlikely to be environmentally acceptable, the oil shale liquids production projections should be considered highly uncertain.

## *Alaska Crude Oil Production*

Projected Alaska oil production includes both existing producing fields and undiscovered fields that are expected to exist, based upon the region’s geology. The existing fields category includes the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. The initial production from these fields occurs in the first few years of the projection, with the projected oil production and the date of commencement based on the most current petroleum company announcements. Alaska crude oil production from the undiscovered fields is determined by the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on the expected capital and operating costs, and on the projected prices. Based on the latest U.S. Geological Survey resource assessments, the remaining North Slope fields are expected to be primarily small and mid-size oil fields that are smaller than the Alpine Field.

Oil and gas exploration and production currently are not permitted in the Alaska National Wildlife Refuge. The projections for Alaska oil and gas production assume that this prohibition remains in effect throughout the projection period.

The greatest uncertainty associated with the Alaska oil projections is whether the heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, will be producible in the foreseeable future at recovery rates exceeding a few percent.

## Legislation and Regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the 5 years following its November 28, 1995, enactment. The volume of production on which no royalties were due for the 5 years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the MMS the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease by lease basis. In the model it is assumed that relief will be granted roughly the same levels as provided during the first 5 years of the act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for oil and gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or gas lease sale occurring within 5 years after enactment. The minimum volume of production with suspended royalty payments are:

(1) 5,000,000 barrels of oil equivalent (BOE) for each lease in water depths of 400 to 800 meters;

(2) 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters;

(3)12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters; and

(4) 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

The water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. The suspension volumes are 5,000,000 BOE for leases in water depths 400 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depth of 1,600 to 2,400 meters; and 16,000,000 for leases in water depths greater than 2,400 meters. Examination of the resources available at 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not materially affect the model result.

The Minerals Management Service published its final rule on the “Oil and Gas and Sulphur Operations in the Outer Continental Shelf-Relief or Reduction in Royalty Rates-Deep Gas Provisions” on January 26, 2004, effective March 1, 2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Production of gas from the completed deep well must begin before 5 years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001.

Section 354 of the Energy Policy Act of 2005 established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through $CO_2$ injection, while at the same time sequestering $CO_2$ produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate funds needed by the Minerals Management Service (MMS) to conduct leasing activities on portions of the Federal Outer Continental Shelf (OCS) and thus effectively prohibited leasing. Further, a separate Executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, with the exception of the Western Gulf of Mexico and portions of the Central and Eastern Gulf of Mexico. When combined these actions prohibited drilling in most offshore regions, including areas along the Atlantic and Pacific coasts, the eastern Gulf of Mexico, and portions of the central Gulf of Mexico. In 2006, the Gulf of Mexico Energy Security Act imposed yet a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

On July 14, 2008, President Bush lifted the Executive ban and urged Congress to remove the Congressional ban. On September 30, 2008, Congress allowed the Congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, the lifting of the Executive and Congressional bans removed regulatory obstacles to development of the Atlantic and Pacific OCS.

## Oil and Gas Supply Alternative Cases

### Rapid and Slow Technology Cases

Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases a number of parameters representing technological penetration in the reference case were adjusted to reflect a more rapid and a slower penetration rate. In the reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on crude oil and natural gas parameters in the reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 50 percent, for the rapid and slow technology cases, respectively.

In the Canadian supply submodule, successful natural gas wells drilled for conventional and tight formations in the Western Canadian Sedimentary Basin (WCSB) are assumed to be 10 percent higher or lower in the rapid and slow technology cases, respectively, than they would be otherwise. For the other unconventional sources (coalbed and shale gas), the assumed undiscovered resource levels are progressively increased or ecreased (in the rapid and slow cases, respectively) over the forecast period to a level reaching 15 percent by 2030. In addition, the otherwise projected production levels for these unconventional sources are increased or decreased (in the rapid and slow cases, respectively) progressively over the forecast period to a level reaching 25 percent by 2030. Finally, the minimum supply prices deemed necessary to trigger the Alaska and MacKenzie Delta natural gas pipelines are progressively decreased or increased over the projection in the rapid and slow technology cases, respectively, downward or upward from 0.0 to 12.5 percent by 2030. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Production costs in the MacKenzie Delta vary across the projection period based on the estimated change in drilling costs in the lower 48 states, indirectly capturing the impact of different assumptions about technological improvement.

## No Shale Gas and No Low Permeability Gas Drilling Cases

The use of hydraulic fracturing in conjunction with horizontal drilling has opened up resources in low permeability formations that would not be commercially viable without the technology. Public concern, however, has been raised regarding the extensive use of hydraulic fracturing because of the large volumes of water required, the chemicals added to fracturing fluids, and the disposal of these fluids after a well has been completed. Another concern is the potential contamination of underground aquifers used for drinking water. Limiting the use of hydraulic fracturing would impact natural gas production from low permeability reservoirs. Two cases were created to examine the impact of not permitting drilling in low permeability formations.

***No Shale Gas Drilling Case***: Starting in 2010, no new onshore, lower-48 shale gas wells are drilled. Gas production from low permeability wells drilled prior to 2010 continuously declines through 2035.

***No Low Permeability Gas Drilling Case***: Starting in 2010, no new onshore, lower-48 low permeability gas production wells are drilled, including shale gas wells and "tight" sandstone and carbonate gas wells. Gas production from low permeability wells drilled prior to 2010 continuously declines through 2035.

Assumptions underlying the drilling of Canadian and other international natural gas wells were not changed.

## *High Shale Gas Resource Case*

Over the last 15 years, as shale gas production expanded into more petroleum basins and as technology improved, the size of the National Energy Modeling System's shale gas resource base has increased. Because the exploitation of shale gas resources is still in its initial stages and because many shale beds have not yet been tested, there is a great deal of uncertainty surrounding the size of the shale gas resource base. A high shale gas resource case was created to examine the impact of increased shale gas resources on the domestic natural gas market. The onshore, lower 48 shale gas resource base was increased by 88 percent from 347 trillion cubic feet in the reference case to 652 trillion cubic feet in the high shale gas resource gas. This case assumes no change in Canadian and other international natural gas resources.

# Notes and Sources

[1] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[2] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[4] Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[5] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of Interior, Minerals Management Service, Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, (February 2006); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[6] Source: Noyes Data Corporation, Oil Shale Technical Data Handbook, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97. The Paraho Oil Shale Project design had a maximum production rate of 100,000 syncrude barrels per day, which is used in the OSSS as the standard oil shale facility size.